PACIFICORP

Community Solar Project Interconnection

Community Solar Project System Impact Study Report

Completed for

(“Applicant”)
OCS040

Proposed Point of Interconnection

Circuit 5R227 out of Campbell Substation at 12.47 kV
(At approximately 42°17'40.32"N, 122°48'9.42"W)

October 27, 2020

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1.0 DESCRIPTION OF THE COMMUNITY SOLAR PROJECT

("Applicant") proposed interconnecting 1.640 MW of new generation to PacifiCorp's ("Public Utility") circuit 5R227 out of Campbell substation located in Jackson County, Oregon, at approximately 42°17'40.32"N, 122°48'9.42"W**.** The project ("Project") will consist of twelve (12) Delta M125HV (factory limited to 117 kW) inverters and two (2) Delta M125HV (factory limited to 117 kW) 118 kW inverters for a total requested nameplate output of 1.64 MW. The requested commercial operation date is May 31, 2021.

The Public Utility has assigned the Project "OCS040."

2.0 APPROVAL CRITERIA FOR TIER 4 INTERCONNECTION REVIEW

Pursuant to the Section I (1) of the Public Utility's CSP Interconnection Procedures, a Public Utility must use the Tier 4 review procedures for an application to interconnect a Community Solar Project that meets the following requirements:

(a) The Community Solar Project does not qualify for or failed to meet Tier 2 review requirements; and

(b) The Community Solar Project must have a nameplate capacity of three (3) megawatts or less.

3.0 SCOPE OF THE STUDY

Pursuant to Section I(6)(g) of the CPS Interconnection Procedures, the System Impact Study Report shall consist of: (1) the underlying assumptions of the study; (2) a short circuit analysis; (2) a stability analysis; (3) a power flow analysis; (4) voltage drop and flicker studies; (5) protection and set point coordination studies; (6) grounding reviews; (7) the results of the analyses; and (8) any potential impediments to providing the requested Interconnection Service, including a non-binding informational NRIS portion that addresses the additions, modifications, and upgrades to the Public Utility's Transmission System that would be required at or beyond the point at which the Interconnection Facilities connect to the Public Utility's Transmission System to accommodate the interconnection of the CSP Project In addition, the System Impact Study shall provide a list of facilities that are required as a result of the Community Solar Project request and non-binding good faith estimates of cost responsibility and time to construct.

4.0 PROPOSED POINT OF INTERCONNECTION

The Applicant's proposed Community Solar Project is to be interconnected to the Public Utility's distribution circuit 5R227 out of Campbell substation via 12.47 kV primary meter. The proposed Point of Interconnection ("POI") will be located at approximately 42°17'40.32"N, 122°48'9.42"W located in Jackson County, Oregon. Figure 1 below is a one line diagram that illustrates the interconnection of the proposed generating facility to the Public Utility's system.

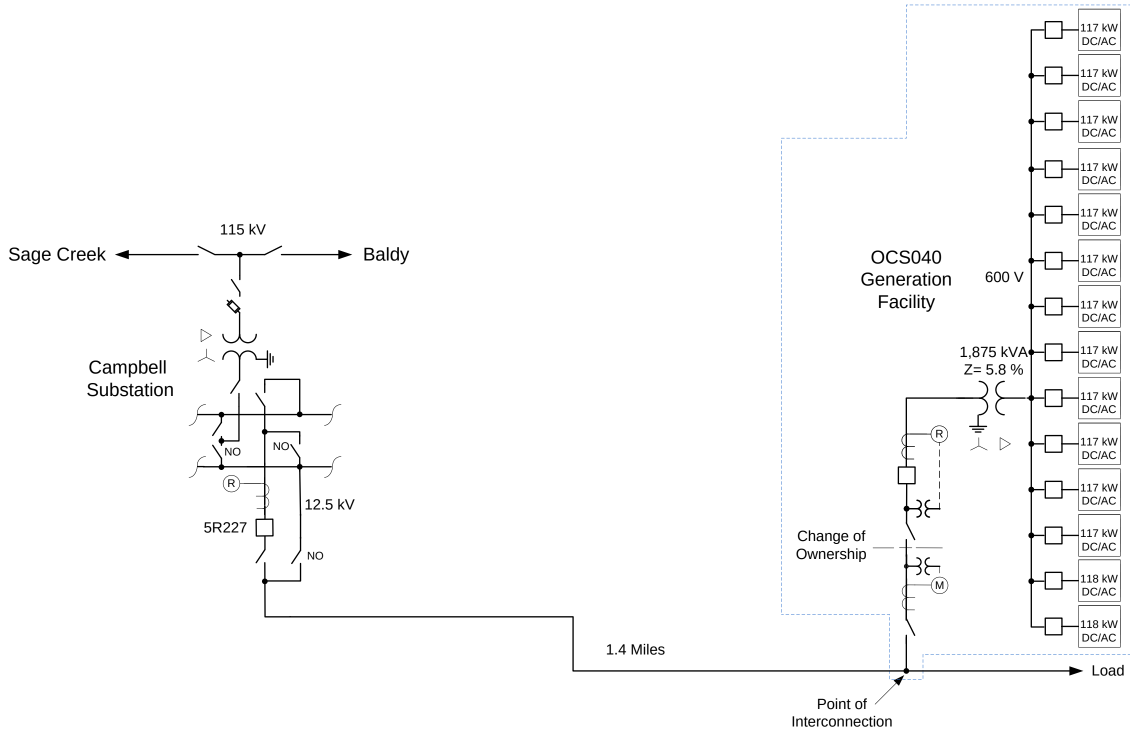

Figure 1: System One Line Diagram

5.0 STUDY ASSUMPTIONS

- All active higher-priority requests for transmission service and/or generator interconnection service (including requests in the traditional interconnection queue and other requests in the Community Solar queue) in the local area of the requested POI will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- The Applicant's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed POI.
- The Applicant will construct and own any facilities required between the change of ownership and the Project unless specifically identified by the Public Utility.
- Line reconductor or fiber underbuild required on existing poles will be assumed to follow the most direct path on the Public Utility's system. If during detailed design the path must be modified it may result in additional cost and timing delays for the Applicant's project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and Public Utility performance and design standards.
- The line extension for this customer is assumed to extend from facility point 01338001.0-037461.

- The generators were assumed to operate during daylight hours, 7 days per week, 12 months per year. The generation contribution at the primary meter change of ownership was assumed to be 1640 kW at unity power factor.
- This study assumes that the Applicant will provide constant power factor control at unity power factor (100% PF).
- A daytime minimum load value of 1822 kW, unity power factor was assumed based on measurements. The new generation is not expected to provide reverse power flow to the circuit or the substation transformer.
- For calculation of the forecasted voltage fluctuation, it was assumed that the power flow from the Applicant would change from full generation to no generation during a one minute interval.
- This report is based on information available at the time of the study. It is the Applicant's responsibility to check the Public Utility's web site regularly for transmission system updates (https://www.oasis.oati.com/ppw)

6.0 REQUIREMENTS

6.1 COMMUNITY SOLAR PROJECT REQUIREMENTS

The Community Solar Project and Interconnection Equipment owned by the Applicant are required to operate under automatic power factor control with the power factor sensed electrically at the POI. The required power factor is 1.0 per unit at the POI. In general, the Community Solar Project and Interconnection Equipment should be operated so as to maintain the voltage at the POI between 1.01 pu to 1.04 pu. At the Public Utility's discretion, these values might be adjusted depending on the operating conditions.

All generators must meet applicable WECC low voltage ride-through requirements as specified in the interconnection agreement.

As per NERC standard VAR-001-1, the Public Utility is required to specify voltage or reactive power schedule at the POI. Under normal conditions, the Public Utility's system should not supply reactive power to the Community Solar Project.

6.2 TRANSMISSION SYSTEM MODIFICATIONS

No transmission system modifications are required to accommodate the Applicant's proposed generating facility.

6.3 DISTRIBUTION/TRANSMISSION LINE MODIFICATIONS

Extend 12.47 kV facilities from existing facility point 01338001.0-037461 to the point of change of ownership. This line extension will require a minimum of two new poles. A three-phase, gang-operated, loadbreak disconnect switch is required on the first pole. A primary metering assembly is required on the second pole. The Applicant will be responsible for obtaining all necessary permits and easements for the Public Utility's line extension.

The Campbell substation T-3402 load tap changer (LTC) requires setting changes to reduce system voltage. Recommended settings are base voltage of 121 volts, and R compensation value of 5, and an X compensation value of 0. The calculated voltage fluctuation from full generation to no generation in the light load case was 1.7%.

6.4 Existing Breaker Modifications – Short-Circuit

The increase in the fault duty on the system as the result of the addition of the generation facility with photovoltaic arrays fed through 12 – 117 kW inverters and 2 – 118 kW inverters connected to a 1,875 kVA 12.5 kV – 600 V transformer with 5.8% impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

6.5 Protection Requirements

The Applicant's generating facility will need to disconnect from the network in a high speed manner for faults on the 12.5 kV line on circuit 5R227 out of Campbell substation. The minimum daytime load on circuit 5R227 is 1,822 kW which is above the maximum potential power output of the proposed OCS040 generating facility. For this reason the imbalance condition of the load and generation can be relied upon to cause the high speed disconnection of the generating facility for faults on the distribution system.

For ground faults on the 12.5 kV bus at Campbell substation the current contribution from the OCS040 generating facility will be greater than the pickup values for the ground overcurrent relay associated with 5R227 at Campbell substation. The overcurrent relay is presently setup to be non-directional. With is configuration 5R227 will be tripped for faults on the other circuits out of Campbell substation which will cause unnecessary and unacceptable interruptions to customers on 5R227 for faults on the other circuits. The relay associated with 5R227 will be configured so that the overcurrent elements are directional. New relay settings will need to be developed for the circuit relay for 5R227 as part of this project so that the ground overcurrent function will only operate for faults on that circuit.

The 12.5 kV circuit recloser planned to be installed at the OCS040 generating facility will need to be equipped with a Schweitzer Engineering Laboratories (SEL) 651R relay/controller and voltage instrument transformers mounted on the utility side of the circuit recloser. The 651R will perform the following protection functions:

1. Detect faults on the 12.5 kV equipment at the generating facility
2. Detect faults on the 12.5 kV line to Campbell substation
3. Monitor the voltage and react to under or over frequency, and /or magnitude of the voltage

6.6 Data Requirements (RTU)

Due to the power size of the generating facility no real time monitoring will be required by the Public Utility for the operation of the transmission network so no RTU will be required.

6.7 Communication Requirements

No communications upgrades are required.

6.8 Substation Requirements

There are no substation modifications required.

6.9 Metering Requirements

Interchange Metering

The metering will be located on the high side of the customer generator step up transformer at the change of ownership. The metering will be installed overhead on a pole per distribution DM construction standards. The Public Utility will procure, install, test, and own all revenue metering equipment. The metering will be bi-directional to measure KWH and KVARH quantities for both generation received and back feed retail load delivered. There will be no additional station service metering for supplying generation load. The metering generation and billing data will be remotely interrogated via the Public Utility's MV90 data acquisition system.

Station Service/Construction Power

The Applicant must arrange distribution voltage retail meter service for electricity consumed by the project when not generating. Temporary construction power metering shall conform to the Six State Electric Service Requirements manual. Applicant must call the PCCC Solution Center 1-800-640-2212 to arrange this service. Approval for back feed is contingent upon obtaining station service

7.0 Cost Estimate

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by the Applicant are not included.

OCS040 Collector Station *Install metering and develop relay settings*	$44,000
Distribution *Line extension/tap, switch*	$69,000
Campbell Substation *Develop relay settings*	$6,000
Total	**$119,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Public Utility must develop the Project schedule using conservative assumptions. The Applicant may request that the Public Utility perform this field analysis, at the Applicant's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

Note: Costs for any excavation, duct installation and easements shall be borne by the Applicant and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by Public Utility to interconnect this Community Solar Project to Public Utility's electrical distribution or transmission system. An estimate, based on finer detail, will be calculated during the Facilities Study. The Applicant will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Applicant.

8.0 Schedule

The Public Utility estimates it will require approximately 10-12 months to design, procure and construct the facilities described in this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the Facilities Study.

Please note, the time required to perform the scope of work identified in this report does not support the Applicant's requested commercial operation date of May 31, 2021.

9.0 Participation by Affected Systems

Public Utility has identified the following Affected Systems: None

Copies of this report will be shared with each Affected System.

10.0 Appendices

Appendix 1: Higher Priority Requests
Appendix 2: Informational Network Resource Interconnection Service Assessment
Appendix 3: Property Requirements

10.1 Appendix 1: Higher Priority Requests

All active higher priority transmission service and/or generator interconnection and Community Solar Project requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection/Community Solar Queue Requests considered:

Queue #	Size (MW)
721	55
741	40
849	100
905	50
971	2.7
1029	400
1031	80
1032	80
1033	80
1034	60
1087	50
1104	3
1120	3
1126	8
1133	80
1134	120
1135	80
1147	2.999
1160	70
1192	238.5
OCS003	0.8
OCS004	0.8
OCS019	0.882
OCS020	0.594
OCS025	2.8
OCS033	1.0
OCS034	0.978
OCS036	1.125
OCS037	1.5
OCS039	2.25

10.2 Appendix 2: Informational Network Resource Interconnection Service Assessment

The study results described above reflect an energy resource interconnection service ("ERIS") evaluation, modified in the CSP program rules to examine only generation and load conditions local to the requested CSP project's interconnection point (sometimes referred to as the "zoomed in view"). The "zoomed in view" functions to: (1) study the project's proposed interconnection without considering certain existing or higher-queued requests outside of the local area; and (2) to inform whether the CSP facility must cap its project to mitigate, although not eliminate, the risk of potential deliverability-related network upgrades to accommodate the proposed CSP generator.

By contrast, the following informational section provides a network resource interconnection service ("NRIS") evaluation performed with traditional assumptions, i.e., not modified to examine only local generation and load conditions, but rather one that assumes that all existing interconnections, higher-queued requests for interconnection service (in both the traditional and CSP queue), and generators with executed contracts beyond the local area are in-service. Depending on the severity of the conditions created when absorbing additional generation (capped or not capped) in that broader, "zoomed out" area, the local area-focused generator size cap developed in the "zoomed in" examination may not be sufficient to mitigate the need for deliverability-related network upgrades. Regardless of this report's informational NRIS results, the deliverability-related network upgrades ultimately necessary to accommodate the proposed CSP generator will depend on conditions present when the future transmission service study is performed, as well as whether network upgrade alternatives are available at that time.

There are currently a significant number of higher-queued requests seeking interconnection in the southern Oregon area where the CSP generator proposes to interconnect. These interconnection studies must be completed before the transmission provider can determine what upgrades and associated cost estimates may be required for the aggregate of generation in the local area to be delivered to the aggregate of load on the transmission provider's transmission system (the NRIS study scope).

10.3 APPENDIX 3: PROPERTY REQUIREMENTS

Requirements for rights of way easements
Rights of way easements will be acquired by the Applicant in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by PacifiCorp. Applicant will acquire all necessary permits for the project and will obtain rights of way easements for the project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation
Real property for a POI substation will be acquired by an Applicant to accommodate the Applicant's project. The real property must be acceptable to Public Utility. Applicant will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Applicant is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

The Applicant must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Applicant will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or able to be permitted use in all zoning districts. The Applicant shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

- Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

- Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Applicant to procure various studies and surveys as determined necessary by Public Utility.

- Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.

10.4 APPENDIX 4: TRANSMISSION/DISTRIBUTION STUDY RESULTS

The Applicant's facilities must be operated in a manner so as not to cause objectionable power quality issues to other Public Utility's retail customers. Voltage fluctuations caused by the generation facility are required to meet the Public Utility's Engineering Handbook, Voltage Fluctuation and Flicker, Standard 1C.5.1 which is found at https://www.pacificpower.net/con/pqs.html. Table 1 of Standard 1C.5.1 indicates that for this project the medium voltage planning levels for voltage fluctuation under any condition is a Pst < 0.9 and a Plt < 0.7. It is the Applicant's responsibility to design and construct a system capable of meeting these levels. Specific system information will be provided on request to the Applicant for design purposes. During operation if measured voltage fluctuation levels exceed the limits specified in Standard 1C.5.1 the Applicant is required to cease generation until the condition is mitigated. The requirement for the Applicant's system to meet Standard 1C.5.1 will be incorporated in the interconnection agreement. The Public Utility may, at its' discretion, disconnect the Applicant's facilities until mitigations to meet these standards are made. The Applicant must also comply with all of the Public Utility's Engineering Handbook standards addressing power quality, including but not limited to Voltage Level, Voltage Balance, Harmonic Distortion, and Voltage Frequency.

Six cases were assembled and studied at the 12.47 kV distribution voltage level.
- Daytime minimum load, no generation.
- Daytime minimum load, full generation.
- Summer peak, no generation.
- Summer peak, full generation.
- Winter peak, no generation.
- Winter peak, full generation.

The following substation load tap changer output voltages were assumed in the respective cases:
- Daytime minimum load case: 1.010 per unit.
- Summer peak case: 1.040 per unit.
- Winter peak case: 1.040 per unit.

Contingency transmission configuration for the Public Utility's system is defined as any configuration other than normal transmission configuration.

Three base cases were developed and studied in power flow simulation at the transmission level covering summer peak load, winter peak load and daytime minimum load conditions. Analysis was performed on each case evaluating two transmission system configurations prior to and with the requested OCS040 generation:
- Normal transmission configuration: Campbell substation supplied from Lone Pine 115 kV source via 115 kV Line 19S.
- Contingency transmission configuration: Campbell substation supplied from Sage Road 115 kV source via 115 kV Line 74.

The results of the transmission study show that the proposed OCS040 project does not result in negative impacts to the Public Utility's transmission system. Power flow simulation indicates that steady state and post transient voltages are projected to remain within acceptable limits and loading on transmission facilities is projected to remain within facility ratings.

There are no contingent facilities identified for this interconnection request at the transmission level.